Final Report

Engineered Geothermal System Demonstration Project

Northern California Power Agency, The Geysers, CA

2008-2009

AltaRock Energy, Inc.

Seattle, WA

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Executive Summary

In June 2009, AltaRock Energy began field work on a project supported by the U.S. Department of Energy entitled "*Use of Multiple Stimulations to Improve Economics of Engineered Geothermal Systems in Shallow High Temperature Intrusives.*" The goal of the project was to develop an Engineered Geothermal System (EGS) in the portion of The Geysers geothermal field operated by the Northern California Power Agency (NCPA). The project encountered several problems while deepening Well E-7 which culminated in the suspension of field activities in September 2009. Some of the problems encountered are particular to The Geysers area, while others might be encountered in any geothermal field, and they might be avoided in future operations.

Changes in well bore design and the drilling plans were required in the early phases of the project as knowledge developed about the chosen *well of opportunity* and the associated reservoir. However, the effects of these changes on budget and risk to project completion were not assessed effectively. Changes in the program resulted in increased technical difficulties specific to drilling at The Geysers that could have been mitigated by having more site-specific expertise. AltaRock has implemented improved staffing, planning, and budget controls to mitigate these risks on future projects based on the lessons learned from this project. By their nature, research and development projects commonly encounter unforeseen impacts to schedule and budget. However, federal regulations do not allow contingencies to be included in project budgets funded by the Department of Energy. Thus, the success of such projects can be threatened by cost overruns arising from unforeseen circumstances if they cannot be borne by the operator.

The experience of this project demonstrated that EGS development can be subject to greater public scrutiny than conventional geothermal and government-funded energy programs. Based on that experience, subsequent EGS demonstration projects now coming to fruition have adopted proactive public outreach programs, and they have been awarded with positive public and press perception.

The potential for public and media technical misunderstanding and consequent delay to project progress are heightened by the innovative nature of EGS technology and the possibility for induced seismicity. In the fall of 2008, when the Induced Seismicity Report for this project was submitted, the IEA-GIA executive committee had not yet adopted the Induced Seismicity Mitigation Protocol (ISMP) (Majer et al., 2008), and the USDOE ISMP (Majer et al., 2011) was still 3 years in the future. Future EGS projects should ensure that a site specific EGS protocol is in place and rigorously supported by governmental agencies providing regulatory oversight. Because data is one of the most valuable products of any technology demonstration, clearly defining data collection, format, confidentiality, and public data dissemination prior to project execution will help project success.

With many of the known conventional geothermal reservoirs already developed, EGS represents the greatest potential for expansion of geothermal energy production in the United States. Studies have concluded that EGS represents a large, indigenous resource of over 2,300,000 MWe (over 500,000 MW in the western U.S.; USGS, 2008) that could economically provide 100 GWe or more of base-load electric power by 2050, while incurring minimal environmental impacts (Tester et al., 2006). With the support of the Department of Energy and the geothermal community, AltaRock will continue development of EGS technology throughout the country.

1. Background

On September 26, 2008, AltaRock Energy, Inc. (AltaRock) received notice of a Financial Assistance Award DE-FG36-08GO18198 from the U.S. Department of Energy (DOE) under the Funding Opportunity Announcement DE-PS36-08GO98008 for the project entitled "*Use of Multiple Stimulations to Improve Economics of Engineered Geothermal Systems in Shallow High Temperature Intrusives.*" The terms and conditions of the award were finalized March 27, 2009. The goals of the project included deepening and hydraulic stimulation of an existing well to create an EGS reservoir, drilling and stimulation of a companion production well (Northern California Power Agency, NCPA, Well E-7) in the reservoir, and flow testing to quantify EGS productivity. The project encountered several problems while deepening Well E-7 which culminated in the cessation of field activities on September 2, 2009. Due to mounting standby fees and uncertainty about when a Finding of No Significant Impact (FONSI) on the Environmental Assessment (EA) for well stimulation would occur, the drill rig was released in October. This document describes the field work, accomplishments and obstacles encountered, and lessons learned from this experience. The lessons learned and suggested solutions offered herein were successfully implemented by the DOE in EGS Demonstrations awarded in 2009. The Newberry Volcano EGS Demonstration Project performed by AltaRock is an example of such a project.

1.1. Funding Requirements

To promote rapid, low-cost technology advancement, DOE has provided funding for geothermal projects that include the work-over of a *well of opportunity* (i.e., an existing well), but has reduced or stopped funding new well drilling. The Funding Opportunity Announcement (FOA) for this project (DE-PS36-08GO98008, *Research, Development, and Demonstration in Enhanced Geothermal Systems*) specified that "recipient cost share must be at least 20% of the total project costs for all well wellbore modification and related activities" but made no similar provision for new well drilling. However, the use of existing wells, particularly those with multiple re-drills or excessive rotating time, has risks not only of high recompletion cost but also of total failure to recomplete, as was the case in this project. Thus, we suggest that the use of a well of opportunity should be thoroughly risk-weighted relative to the cost of drilling a new well.

2. Site Selection

Site selection began in the summer of 2007, starting with identifying the characteristics critical for a suitable site and developing a site selection matrix. Favorable characteristics included:

- A reservoir with temperatures near 250 °C at a relatively shallow depth of 4 km or less.
- A well of opportunity that could be stimulated without a workover was desirable, but an existing well that could be deepened was also considered favorable.

- Previous EGS demonstrations have occurred primarily in crystalline rock in shear- or normal-faulting stress regimes with some pre-existing jointing or fracturing, and so candidate sites in similar geologic regimes were attractive.
- Existing data availability and quality, including image logs, temperature surveys, and geophysical data.
- An existing seismic monitoring system and background data to assess stress conditions and determining the potential for seismic hazards and induced seismicity.
- An existing power plant, with spare capacity and existing transmission and water supply.

The potential for conducting a demonstration was discussed with the operator at each site considered. Some sites could not be pursued due to an inability to negotiate with the site owner or a change in ownership that was in progress. Ten sites were considered for the demonstration project. The NCPA Geysers site for was chosen because:

(1) it scored the highest based on selection criteria, including having wells of opportunity and a studied, hot, granitic formation that was identified as ideal fracture media for EGS;
(2) AltaRock was able to establish a viable Cooperation Agreement with NCPA;
(3) the existing and extensive Geysers geologic database was advantageous for planning;
(4) existing NCPA power plants, operating at about 50% capacity, have a current need for additional steam and would allow long-term testing at nominal additional cost; and
(5) numerous essential permits and an Environmental Impact Statement (EIS) were already in place, including an exhaustive study of the potential for seismic hazards and induced seismicity; and
(6) project scheduling was reduced up to two years by having use of water from the South East Geysers Effluent Pipeline ("SEGEP").

NCPA originally offered three wells to AltaRock as workover candidates one of which was viable, Well E-7. The advantages of this well included:

- plenty of access room on the well pad;
- it did not have to be completely re-drilled, unlike other well candidates;
- the well was on a pad by itself, with ample room for workover, stimulation and testing equipment and activities;
- workover and stimulation would not interfere with existing operations; and
- the initial cost and risk analysis for deepening well E-7 were lower than that for completing an equally deep new well; however, cost and risk were not adequately reassessed when it was determined that the well had to be deeper than originally planned requiring increased drilling time and a more casing string.

> **Lesson Learned:** A rigorous cost-based risk analysis should be completed for EGS projects and must use accurate information and be reassessed as the project continues and scope changes occur.

1.2. History of NCPA Well E-7

Well E-7 was drilled on the lower E-pad of the NCPA lease in 1988, and completed with three legs (Figure 2). The first two legs (OH and RD1) penetrated the felsite reservoir target strata at depths of 9440 feet and 9950 feet below ground surface (bgs). These legs were plugged with cement and a third leg (RD2) was drilled to a depth of 7855 feet bgs through a window cut in the casing liner at about 4500 feet. None of the legs were productive, likely due to the location of the well in the extreme southeastern extent of the Geysers reservoir, and the well was idled. In fact, no wells on the lower E-pad were used for production or injection until March 2008.

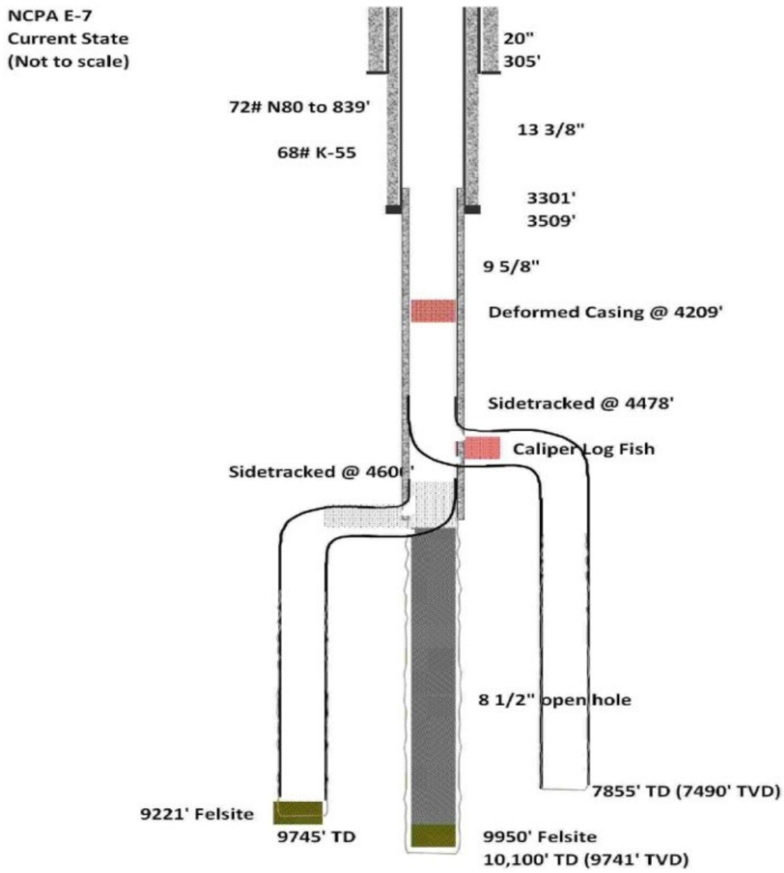

Figure 1. Existing well E-7 conditions prior to well workover.

Injection into Well E-2, located on the upper section of the same well pad, began in July 2003 and continued for 21 months until March 2005, at an average rate of 400 gpm (about 17 million gallons/month). Well E-2 is on the upper E-pad and is directionally drilled to the northwest. At casing shoe depth there is over 1000 feet of horizontal separation between the E-2 and the uppermost open hole (RD2) of E-7. In February 2008, NCPA filed a sundry notice to convert the idle E-7 to an injection well for additional injection in the area. In support of that notice, an 8 ½ inch bit was run into the hole and a tight spot in the 9 $^5/_8$ inch liner was found at 4368 feet. During a subsequent caliper survey, the tool separated from the wireline at 2100 feet and could not be fished out, and was left in the open hole at a depth of 4566 feet. Next, a video log run to the depth of the stuck fish to examine the 13 $^3/_8$ inch casing and 9 $^5/_8$ inch liner showed a damaged collar at 4207 feet. The 20 year old well was deemed suitable, and injection started in May 2008.

The source of water injected at E-7 was the SEGEP, which enters NCPA property at the E-pad. SEGEP fluids are 50-67% reclaimed water, depending on the season, with the rest being Clearlake water. According to the sundry notice, NCPA planned to inject 500 gpm (about 22 million gallons/month) into E-7. The planned injection rate was reached in August 2008, at which point it was 15% of the total field injection by NCPA. Injection at E-7 ceased prior to AltaRock's workover activities that began in June 2009, and injection at E-7 had lasted for just over a year.

If the serpentinite that serves as the cap to the steam reservoir in the Geysers is exposed to fresh water, it can become very weak and even flow, making drilling through this formation very difficult. Most of the wells drilled through the serpentinite cap in the Geysers were drilled in the 1980's, before widespread water injection began in 2003 (in the case of the southeast Geysers). Well bore stability problems were recently reported in several wells in the Bottle Rock area, and largely attributed to hydration of the formation by injected water. The problematic lithology at Bottle Rock is argillite, which is similar to, but somewhat more forgiving, than the serpentinite. The extent to which the serpentinite may have been hydrated and weakened by E-pad injection prior to AltaRock's efforts to re-drill E-7 is difficult to ascertain. In 2008, prior to injection, the E-7 casing appeared to be in good condition except for the damaged collar at 4207 feet.

1.3. Drilling Plan

A well workover plan was presented in the application to the DOE in response to the FOA (Figure 2). The plan was to deepen well E-7 2000 feet into the felsite unit by re-drilling the well from 3200 feet bgs to 10,500 feet bgs and then creating an EGS in the felsite instrusive. A 9 $^5/_8$ inch casing was to be set to 9,500 feet bgs (casing shoe depth), below which would be a 1000 foot interval of 8.5 inch open hole (Figure 2Figure 2). The 1000 ft cased interval in upper felsite (8500-9500 feet bgs) was to be a buffer between the overlying commercial steam reservoir and the EGS zone. This buffer was required by the field operator NCPA to separate the "normal" Geyers steam reservoir from the planned EGS reservoir.

After the DOE award was granted, a detailed study was conducted on previous seismicity in the southeastern Geysers area. Analysis found a normal regional faulting stress regime (i.e., vertical σ_3) using the stress inversions of focal mechanisms determined by the University of California Berkeley Seismological Laboratory (UCB, 2009). Results at other EGS projects indicates that a normal stress regime may result in vertical fracture growth during stimulation, and so it was determined that the well should be completed deeper to maintain the required 1000 foot buffer. Thus, the plan was revised to set the casing shoe at 10,500 feet bgs and deepen the well to 12,000 feet bgs. This change resulted in significant changes in casing and cementing design and cost,

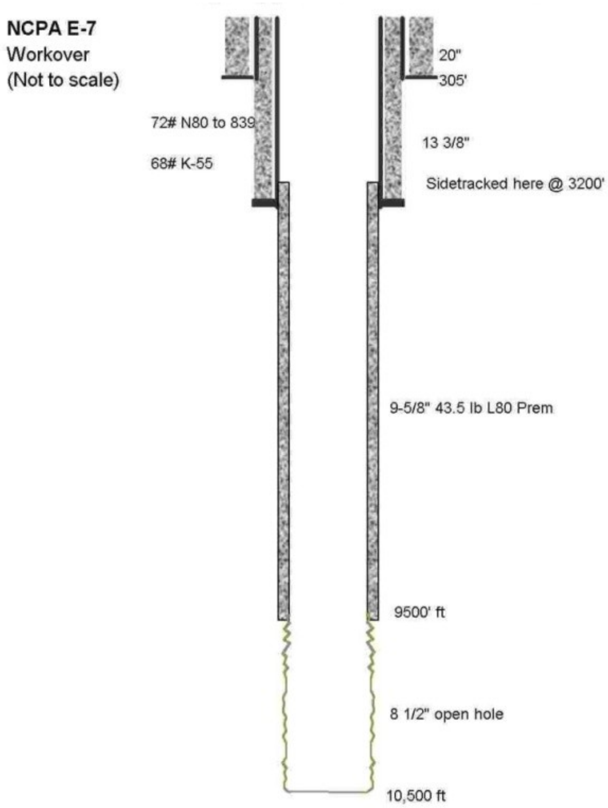

Figure 2. Idealized schematic of original well workover plan from proposal (sidetracks not shown)..

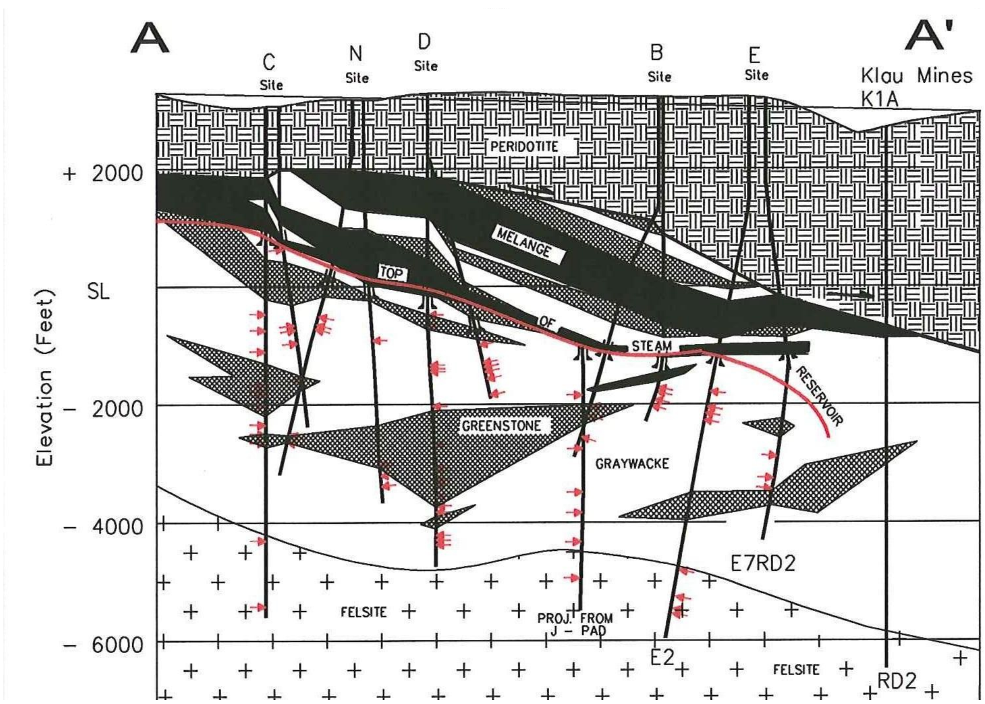

Figure 3. Lithologic Section at possible windows in casing.

including a larger drill rig and more rig operating days; the forecasted drilling cost increased from $3.7M to $5.9M. In addition to this substantial cost increase, these changes in well design also increased the risk of unsuccessful completion because the serpentinite and mélange would be exposed to air and fresh water for a longer time with the deeper drilling. The impact of these changes on the risk profile was not fully appreciated during the planning process.

The well plan included a window depth at 3200 ft bgs (Figure 3) to accommodate the new 13 $^{3}/_{8}$ inch casing, which had to be sidetracked from the well bore within the existing 13 $^{3}/_{8}$ inch casing (Figure 1). The plan was to set a cement plug in the existing casing, place a whipstock in the well and mill a 12 ¼ inch hole, and extend 9 $^{5}/_{8}$ inch casing up to about 9,500 ft bgs. This varies considerably from typical well completions in the Geysers in that well sidetracks are typically started in the more competent bedrock encountered below the serpentine caprock, as previous sidetracks have been completed in well E-7. Deviating the well bore through the serpentine would prove much more problematic than AltaRock was led to believe.

Analysis of the well plan prior to field activities identified anticipated drilling problems:

- Lost circulation problems which are more common in offset wells.
- Care should be exercised in the window area when making trips. Trip speed and drag must be monitored through this area to avoid mechanical hang-up.
- A mist system will be operated to mitigate dust with care not to use too much water and cause swelling of clays.
- The hydraulic mud system is a simple freshwater gel.

Lesson Learned: In existing well workover situations, the risk that previous operations have negatively affected the wellbore and/or the formation needs to be better assessed and periodically reevaluated. Furthermore, when a project is restricted by legal (or other) non technical requirements (e.g., the 1000 foot buffer requirement imposed by NCPA), additional care should be taken in the well design to consider factors which might interfere. This especially true in an agency funded research project such as this where financial contingencies are not an option.

3. Workover and Deepening of NCPA Well E-7

1.4. Summary of Drilling Events

AltaRock operations in E-7 commenced May 27, 2009 with the installation of a bridge plug at 3289 feet, followed by a casing and cement integrity log, and replacement of the wellhead. These operations were completed June 4. The sidetrack and deepening of E-7 began June 20, 2009. The drilling history is summarized below and in Figure 4 and detailed in Appendix A. All the depths described are given in feet bgs.

- **RD3 (3203-4434 feet)**
  A window in the 13 $^{3}/_{8}$ inch surface casing was cut between 3203 and 3241 feet and into the surrounding serpentinite. Initially, the well was drilled with mud to about 3345 feet. Drilling was then switched to air to increase the drilling rate and in anticipation of expected loss zones deeper in the borehole. Air drilling in the serpentinite was done using a water mist system to suppress asbestos-laden drill cutting dust from being discharged through the drilling muffler. When well bore stability problems resulted in bridges and tight spots, drilling was switched back to mud. During the switchover, cuttings were flushed from the borehole with fresh water. The hole was drilled with mud down to 4266 feet where circulation was lost. Drilling was then switched back to air and drilled down to 4434 feet. Tight spots and bridges were encountered when the hole was reentered after tripping for bit changes and drilling with mud was resumed; the borehole was again flushed with fresh water while the mud was prepared. Difficult tight spots, stuck pipe, and the need to ream and re-drill the hole occurred with every bit change. Finally, during a bit change at 4434 feet, soft serpentinite formation material flowed up into the casing; the original hole could not be found and the borehole sidetracked on its own.

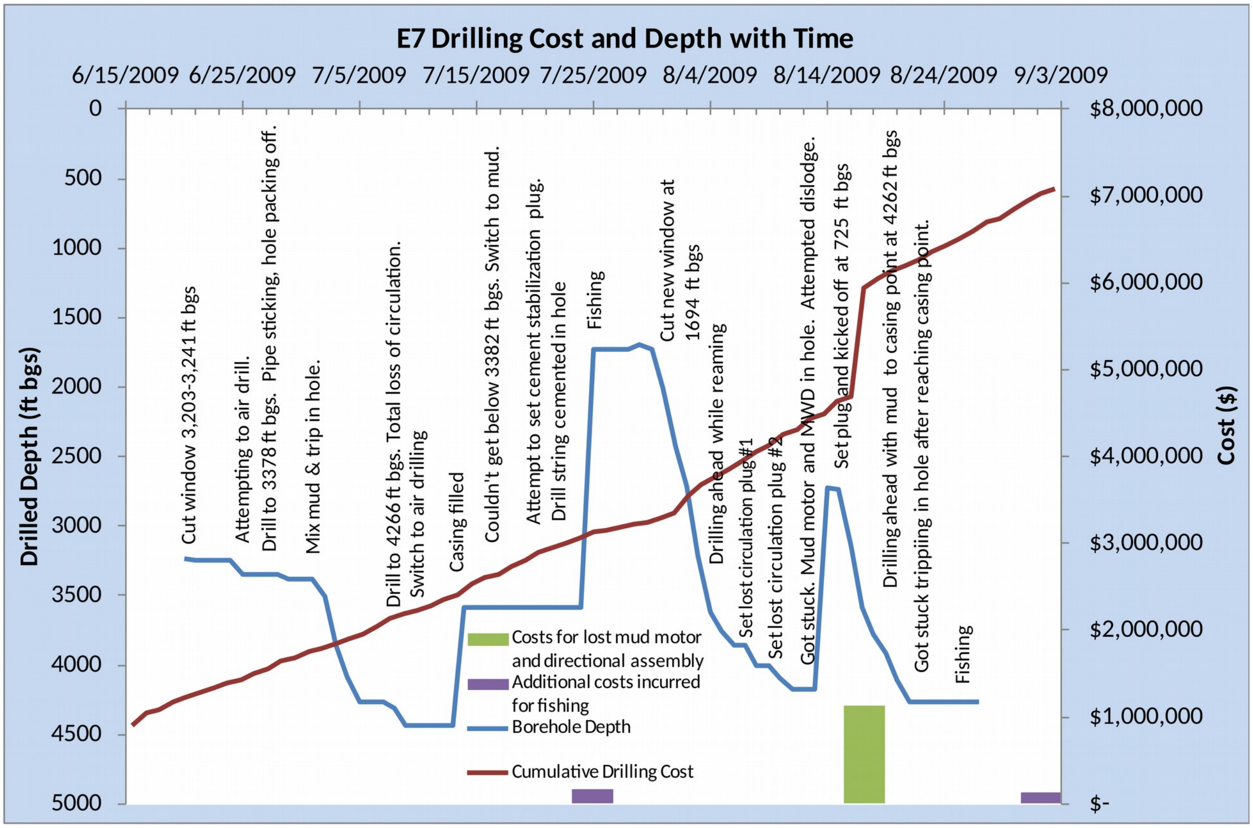

Figure 4. Drilling progress and cumulative project costs over time. The bar graphs at the bottom of the graph illustrate the material and tool costs associated with fishing work and loss of drilling equipment; standby and labor costs are not included. The graph is annotated to show the timing of significant events.

> **Lesson Learned:** Drilling of serpentinite should only be performed using properly conditioned drilling mud. Air drilling, especially misted air, and fresh water must not be introduced in the hole prior to casing installation.

- **RD3ST1 (3383-3585 feet)**
  With great difficulty and an incident of stuck drill pipe, the hole was sidetracked to 3585 feet. Due to these continuing difficulties, we initiated a redesign of the casing program to isolate the unstable formation. While this was being done, an attempt was made to stabilize the hole for re-drilling using a lightweight cement plug. The plug was planned as a typical lost circulation plug with a fairly fast setting time and a large amount of excess. However, the instability of the borehole prevented the drill pipe from being removed before the cement had set. The cement came up the hole higher than anticipated, and the lower portion of the drill pipe was accidently cemented in the hole. The drill string above the lodged section was backed off and removed, followed by nine days of unsuccessful attempts to remove the cemented portion of the string (see daily reports between 7/15/09 and 7/24/09 in the Appendix). Plans were made to mill out a new window and begin RD4. The rig was placed on standby waiting approval of a sundry notice to create another sidetrack by the BLM.

> **Lesson Learned:** Ensure that the drill string can be removed before the cement set time before proceeding. Lessons learned during cementing and fishing are described below.

- **RD4 (1674-4175 feet)**
  Drilling began again on July 29 with a new window cut in the 13 $^{3}/_{8}$ inch casing between 1674-1694 feet and above the stuck drill pipe. A new drilling mud provider, Chemtech Services, LLC, was contracted and the hole was drilled with mud to a depth of 4175 feet. Chemtech has experience working in The Geyser's serpentinite and formulated an improved drilling mud combination. A successful innovation in this section was to ream while drilling. The need for a larger diameter hole to accommodate an 11 ¾ inch casing required that the hole be reamed to 14 ½ inch for sufficient casing clearance and successful cementing. Reaming while drilling was chosen to speed the re-drill and get a bigger hole in one pass. However, this meant that a mud motor and directional drilling equipment were in the hole when, on August 12, the drill string stuck on bottom soon after a loss zone was encountered. The flow of drilling fluid into the loss zone may have pulled down cuttings around the string of the large diameter tools. An antenna with a signal booster assembly that had been installed in the drill string to boost the directional

information to the surface prevented fishing of the mud motor and directional equipment, and the equipment was lost in the hole.

> **Lesson Learned:** When drilling in high risk formations, the bottomhole assembly should be configured for maximum potential success if fishing is required, and the use of expensive tools should be minimized.

- **RD4A (2733-4262 feet)**
  A fourth sidetrack began on August 15, and drilling on mud progressed quickly to a depth of 4262 feet, which was determined to be a good casing point. However, the drill pipe became stuck in a bridge at 2981 feet while running in the hole on August 22. After another unsuccessful retrieval operation lasting 7 days, the fish was cut off and left in the hole. Drilling operations were halted on August 31 and the borehole was temporarily abandoned with a cement plug at 2021 feet. Drilling operations were suspended on September 2, 2009, and the rig was released in October.

1.5. Serpentinite Hydration

The lack of success in deepening the E-7 well may be related the previous use the well as an injector. Water injected at the shoe of the casing 4600 feet bgs (Figure 2) would only have to migrate about 140 feet horizontally to hydrate serpentinite at the shallowest depth of the first re-drill (E-7 RD3). The RD4 and RD4A re-drill boreholes were further away at about 800 horizontal feet. Hydration of the serpentinite may also have occurred due to annular flow outside the casing. This would result in serpentinite instability just outside the two windows that AltaRock cut in the casing to initiate each re-drill. The E-7 RD3 window did eventually became unstable and tight which could have been due to serpentine hydration during weeks of drilling rather than pre-existing conditions. No tightness was reported at the depth of the window of E-7 RD4. Water injection could have resulted in hydration and destabilization of the serpentinite and contributed to the drilling problems encountered in attempts to deepen E-7.

1.6. Drilling Fluid Management and Solids Control

The choice and maintenance of the drilling fluid system is critical for the success of any drilling operation. The Geysers reservoir geology presents a number of significant challenges, including drilling through steam cap formations containing the unstable serpentinite and mélange, the production interval of greywacke, and then the felsite. During the drilling of E-7RD3 and E-7RD3ST1, misted air and drilling mud were interchanged as drilling fluids. Additionally, the hole was circulated clean with fresh water on two occasions. Exposing serpentinite to fresh water can causes the talc, asbestos fibers, and clay to separate, liquefy and become even more unstable. In addition, the action of drilling can mechanically separate the components of the serpentinite and hasten its liquefaction. E-7RD4 and E-7RD4A were drilled only using mud which improved the drilling conditions. However, having to re-drill from a start depth of 1674 feet meant that a much longer interval of serpentinite was exposed and hydrated by drilling. Even under the best of circumstances, the serpentinite does not remain stable for very long, so by the time the third re-drill was attempted the formation was very unstable. Two methods were used to try to delay hydration and degradation of the serpentinite formation. First, drilling fluid loss was controlled via additives to prevent hydration of the serpentinite along microfractures. Second, mineral oil and other additives were added to the drilling fluids to enhance adhesion and slow water incursion into the rock matrix. Nonetheless, sloughing and continual instability were never successfully controlled.

Another problem that compounded difficulties in the serpentinite is the need to prepare for the loss of circulation that typically occurs in the underlying mélange. The mélange (French for mixture) is an ancient thrust fault comprising blocks of different rock types jumbled together, with open fractures in some areas. Because the serpentinite needs to be drilled with mud and pressure in the underlying steam zone is very low, when fractures are encountered in the mélange sudden losses of the drilling fluid can occur, rapidly draining the borehole of mud and pulling formation down around the drill pipe and bottomhole assembly and frequently results in stuck drill pipe. This is one of the biggest causes of stuck pipe in geothermal drilling and is often mistaken for differential sticking that occurs in the oil and gas drilling through porous sedimentary formations. However, mud filter cake does not build-up on the bore wall of the low-porosity formations usually drilled in geothermal field, and instead fluid is lost to the formation through large open cracks. Thus the methods used to deal with differential sticking do not work well for these fracture-controlled, stuck pipe problems encountered in geothermal drilling. Unfortunately, due to a lack of experience at The Geysers, the AltaRock drilling team misdiagnosed the causes of stuck pipe on more than one occasion. Consequently, attempts to unstuck the pipe failed.

1.7. Cementing

Cement plugs are commonly used in geothermal wells to control dramatic loss of circulation. Setting open-hole cement plugs is a normal operation but can present specific challenges while drilling in The Geysers, especially when drilling through formations containing serpentinite. On July 15 an attempt was made to stabilize the flowing serpentinite formation by setting a lightweight, open-hole cement plug at 3394 feet. Very large amounts of cuttings had been removed from the hole, and it was suspected that this left a large, open cavity of unstable serpentinite. The cavity volume was calculated based on the amount of cuttings removed, and also by tagging the circulating fluid and calculating the timing of bottoms-up. Using these methods, the well bore diameter was calculated to be 35 inches, a cross-sectional area 8 times that if the bore hole had not significantly sloughed and was still the drill bit diameter of 12 ¼ inches. Based on this calculation, a large volume of cement was pumped. The top of cement ended being much higher than expected and the drill pipe could not be tripped out of the hole before the cement set and solidified. Consequently, the drill pipe became cemented in the hole.

Subsequent evaluation of the job indicated that only an effective 18-inch open hole was filled with cement, with the remaining excess flowing farther up the hole. The over-estimation of the effective hole size may have been due to formation flowing back into the zone from which excess cuttings were removed, or that the drilling fluid gelled due to the higher than expected temperature in the hole and could not be displaced by the pumped cement. Calculating cement volumes is difficult, and it is usually considered safer to pump too much cement which can be drilled-out rather than too little cement which incompletely stabilizes the hole. Other important factors contributing to the pipe being stuck:

- A check valve used in the drill pipe by the rig crew delayed attempts to pull the drill pipe out of the cement.
- Cement composition caused rapid thickening time which is good for loss plugs but not for hole stabilization.
- A slow trip time while pulling drill pipe out of the hole.

Procedures and cement slurry composition were modified. Subsequently, two additional open-hole cement plugs were successfully set in the mélange formation to manage circulation control without incident. Modifications included:

- Cement was formulated to achieve a longer thickening time and slower static gel strength.
- The borehole was widened up to 30% in excess of the 12 ¼ inch bit size, with additional plugs used if excess is not sufficient.
- Eliminating use of check valve in drill pipe to decrease trip time after cement placement.

Lesson Learned: More effective techniques for calculating wellbore diameter during drilling may be key to limiting equipment losses and lowering costs. Personnel with local site experience should advise on the appropriate cement composition. In addition, they failed to prepare and follow a written procedure to trip the bit out of the hole quickly after placement of the cement plug.

1.8. Fishing

Drill pipe and other equipment became stuck in the borehole three times. The first instance (July 15) followed the cementing of the drill string in the hole. After a three days delay for equipment delivery, coiled tubing equipped with a mud motor and bit were used to successfully remove cement from inside the drill string. During the following six days attempts were unsuccessful at washing over and jarring the pipe loose. Site personnel did not accurately gauge the likelihood of fishing success, and should have stopped sooner. The top of the fish was left at 1727 feet, requiring the subsequent re-drill to start at 1672 feet which greatly increased the amount of serpentinite that would have to be drilled through.

The second fishing job (August 13) was required after sloughing of serpentinite formation resulted in the drill string, a mud motor and MWD tools becoming stuck on bottom at 4175 feet while crews were making a new connection. This time, fishing attempts were halted after 48 hours of unsuccessfully attempting to jar the fish loose.

The third instance of fishing (August 22) was similar, with the drill pipe, mud motor and other tools getting stuck in a likely serpentine-slough bridge at 2981 feet while running into the hole with a total depth at the time of 4262 feet. Unsuccessful attempts were made to jar and vibrate the fish loose over the following seven days, while serpentinite continued to cave into the hole.

The third incident showed that the drilling didn't learn from previous mistakes. Given the increasing instability of the hole, the likelihood of getting stuck should have been realized and the cost risk mitigated by using a less valuable bottomhole assembly. Also, given the lack of success in the previous fishing operation, fishing operations should have terminated sooner.

> **Lessons Learned:** The increased cost and risk of the program changes should have been more thoroughly compared to other options, including abandoning E-7 and drilling a new well. Drilling in active reservoirs with unstable formations increases the risk of drilling trouble and fishing costs. These risks should be adequately factored into total drilling cost, and mitigated with the use of site-experienced drilling personnel. The use of an existing well required more difficult directional drilling and more expensive tools in the hole. The use of expensive down-hole tools should be carefully weighed against lost-in-hole risk and cost. The likelihood of success, duration, and cumulative cost of fishing jobs should be considered before mobilizing the fishing equipment.

4. AltaRock Operations

General drilling experience is important to geothermal drilling success, but the Geysers has unique challenges. Specific geothermal drilling techniques, mud systems, cementing procedures, and experienced personnel are critical to success at The Geysers. However, most of the wells operating at The Geysers were completed in the 1980s, and much of the institutional knowledge for operating in this field has been lost. Many of the drillers familiar with working in serpentinite and the use mud that prevents wetting of the serpentine are gone. The AltaRock drilling manager and crew had experience drilling in the Salton Sea and in oil and gas fields but not in The Geysers, and they did not appreciate the sensitivity of serpentinite to water. A more appropriate drilling plan might have been created if the drilling manager been more proactive about soliciting advice about techniques for drilling the serpentine.

Hiring decisions and drilling company selection were based more on personal connections and past working relationships than on experience in the Geysers (Note that the executives and project team members that made these decisions are no longer with AltaRock, and did not provide rational for their decisions before leaving). While very experienced in drilling, only one of the consultants hired by AltaRock had Geysers experience. The drilling contractor began the job using personnel with geothermal experience (though not in The Geysers), but replacement personnel resulted in a progressive decline in experience as the project continued. AltaRock sought increased participation and advice from NCPA's drilling expert Ray Otwell as drilling troubles mounted. He provided several improvements, but serpentinite sloughing problems continued due to past mistakes.

AltaRock did implement significant changes to the drilling program as new information became available, but the increases in cost and risk were not assessed in a timely manner – a consequence of poor project management. Timely financial updates information were not provided while drilling was underway which illustrated the lack of communication that eventually led to exorbitant cost overrun; final costs were almost double what the pre-drilling cost estimate was for the entire well. DOE officials repeatedly requested updated financial information on the drilling operations as it proceeded, but these requests were not satisfactorily met.

> **Lessons Learned:** Site-specific experience requirements should be clearly delineated prior to job initiation, and maintained through project completion.
>
> The compounded risk of start-up drilling and R&D technology requires resourcing of management, tools and personnel at a higher than traditional level.
>
> Expenses must be closely tracked and reported to the funders, with clear up-to-date metrics comparing planned and actual spending.

5. Induced Seismicity

AltaRock began its dialogue with NCPA in July of 2008 with a presentation about its EGS technology, its capability and a proposal to work together at an NCPA site in the Geysers. Following weeks of discussions with NCPA staff, its environmental consultants and outside counsel it reached agreement to work cooperatively. Considerations for the project included complete review of California Environmental Quality Act compliance, assessment of Lake County and California Division of Oil, Gas and Geothermal Resources requirements as well as Bureau of Land Management's lease restrictions and permit protocol. In September, prior to receiving the award for DOE funding for the project, AltaRock and NCPA met with the BLM, State and County regulators to discuss the project and to develop a plan for permitting and review of the proposed activities in light of the potential for induced seismicity.

It is has been well known for years that geothermal production and injection activities can cause earthquakes which can be felt by local populations, as can many other human activities such as oil and gas production and injection, mining and reservoir fill up. The DOE has sponsored a series of workshops on the issue which reviewed the science and the engineering practice that developed to mitigate potential impact of earthquakes generated by geothermal production and injection and in particular EGS injection and stimulation. One of the primary outcomes of these workshops is that while careful site selection and studies of seismic hazard can provide a solution to mitigate the risk of generating seismicity of concern to local populations, public education and awareness are paramount in the successful development of a project.

AltaRock established a public outreach plan at the earliest stages of the project to foster public awareness. Lists of outreach events are included in Table 1 and Table 2. In light of the potential for induced seismicity, AltaRock and NCPA met with the BLM and State and County regulators to review the project and discuss permitting prior to even applying for DOE funding. At that meeting both the ongoing induced seismicity issues with geothermal production and injection at the Geysers and the history of induced seismicity at other EGS projects including the suspension of the Basel EGS project being done by Deep Heat Mining was discussed.

In October, prior to the announcement of the DOE grant award, AltaRock introduced itself to the Anderson Springs Mitigation Committee made a presentation discussing the company, the technology, the project and its relationship with NCPA. AltaRock attended every subsequent committee meeting and became a voting member of the committee through Lake County Board of Supervisor approval in July 2009. AltaRock has also presented to and joined the Seismic Monitoring Action Committee formed by Geysers-area communities and geothermal operators.

AltaRock made presentations and attended meetings of the NCPA Utilities Committee, Utility Directors Meeting and Board of Commissioner meetings. Once the EA was complete and released to the public, AltaRock coordinated and participated in a public meeting for which statutorily compliant public notice was made. AltaRock presented its plan and answered public questions at this meeting held in Anderson Springs.

NCPA and AltaRock held a special meeting with representatives of Anderson Springs Homeowners Association in April of 2009 to respond to its questions and concerns that were

Table 1. AltaRock Public Presentations

Date	Audience
August 2008	NCPA
September 2008	BLM Ukiah Staff / DOGGR/ NCPA
September 2008	NCPA Facilities Committee –public meeting
October 2008	Anderson Springs Mitigation Committee Includes Lake County Supervisor
October 2008	NCPA Board of Supervisors
March 2009	BLM Public Meeting in Anderson Springs
May 2009	Seismic Monitoring Committee Anderson Springs

expressed during the public comment period and at the aforementioned public meeting. At the special meeting AltaRock committed to install a strong ground motion sensor to supplement the existing sensor in Anderson Springs; to donate money to the Anderson Springs Sewer and Water District; to contribute to the mitigation fund; and to establish communication protocols with the community. The AltaRock demonstration project website was also discussed and Anderson Springs has been involved in the development of the website as an aid in providing information interesting to the community, including real time posting of seismic event locations.

Table 2. AltaRock Representation at Community Meetings

Date	Participant
November 2008 January 2009 April 2009	NCPA NCPA NCPA
November 2008 January 2009 February 2009 April 2009 May 2009	Anderson Springs Mitigation Committee Anderson Springs Mitigation Committee Anderson Springs Mitigation Committee Anderson Springs Mitigation Committee Anderson Springs Mitigation Committee
April 2009	Special Meeting with Anderson Springs Homeowner Association Representatives
July 2009	Lake County Supervisors

6. DOE Methods and Communications

The Geysers/NCPA experience has shown that EGS development may be subject to a significantly higher degree of publicity and scrutiny than other geothermal and government-funded programs. Because data is one of the most valuable products of any technology demonstration project, defining the data to be collected, what will be made publicly available by AltaRock and DOE, and how quickly data should be released, will allow applicants to plan and budget for this from the beginning.

> **Lesson Learned:** Data reporting requirements, including confidentiality, format, distribution and frequency must be clearly delineated prior to commencement of operations and supported throughout the project.

Due to the innovative nature of EGS technology, the lack of an established technical protocol and procedural roadmap for stimulation and control of induced seismicity made likely the potential for public and media technical misunderstanding and consequent project impacts. Future EGS demonstrations should ensure that an EGS protocol, modified appropriately for each site, is in place and is rigorously supported by governmental agencies that have provided regulatory approvals and permits.

> **Lesson Learned:** Rigorous site-specific EGS protocol must be established as part of project planning and receive support from regulatory agencies through project completion.

DOE funding programs provide no allowance for contingency funds. However, R&D activities, by their very nature, often encounter unexpected changes in plan and cost. This is particularly true for drilling or other subsurface operations, especially those involving a 'well of opportunity'. For DOE-sponsored, cost-share projects involving private companies, cost-overruns become the sole responsibility of the private company, which may decide to abandon the project rather continue.

7. Public Outreach

The primary lesson learned is that EGS projects need a plan for public communication regarding project goals and risks. Such plans should be developed by both the principal investigator and sponsoring entity and the funding agency, in this case the DOE. The plan needs to be in place prior to release of funding for the project and should begin when an award is announced. Both AltaRock and the DOE were surprised by the adverse publicity generated by the publication of articles in the New York Times linking the DOE funded research project at the NCPA Geysers area to the potential for damaging seismicity. Having a proactive strategy for public communications in place before the beginning of the project could have diverted the impact of the negative publicity. The public could have been informed about the past studies of injection induced seismicity and ongoing DOE-funded monitoring efforts at the Geysers. DOE-sponsored workshops on geothermal and EGS induced seismicity would have demonstrated that the DOE was aware of the issue and had conducted ample studies of induced seismicity to support a field project. The protocol AltaRock had developed with the BLM for monitoring the stimulation and mitigating seismic risk was a documented part of the BLM Finding of No Significant Impact (FONSI) for the project several months prior to the publication of the first article. None the less, the negative publicity from the New York Times articles swayed public opinion against the project which delayed and impacted the project's success.

8. Summary of Lessons Learned

- **Lesson Learned:** A rigorous cost-based risk analysis should be completed for EGS projects at the time of project planning, including:
    - Cost of power based on temperature, depth, drilling costs, conversion efficiency, flow per well, injection pressure, production pressure, plant construction costs and transmission and interconnect costs. As new information is received the costs should be updated.

- Permitting risk including all phases of project permitting from installing microseismic monitoring equipment to construction of a power plant with transmission lines.
- Seismic hazards risk including induced seismicity from both injection during stimulation and long term project operation. This assessment should include probabilistic analysis of background seismicity for maximum event size and recurrence interval, mapping of faults and fractures in the area, deterministic analysis of maximum event size based on stresses and fault and fracture length as well as calculation of seismogenic index.
- Water availability for both stimulation and long term operation including cooling water.
- Community acceptance risk that the project, while permitted successfully will not be fully accepted by the community.
- Risks associated with stimulation. These include: Suitability of rock for stimulation, stress magnitudes impact on both stimulation pressures and operating pressures, well configuration impact on stimulation success, existence of natural fractures and impact on leak off of water during stimulation and operations availability of diverters for the rock type and temperature and availability and cost of suitable pumping equipment for stimulation and long term operation.

- **Lesson Learned:** If a well of opportunity (exiting wellbore) will be used, the condition of the well and the risks associated with workover of the well need to be carefully assessed. Many times, a new well is cheaper than the cost of a workover in an old or damaged wellbore once the cost of risk has been included. In workover situations, the risk that existing operations have negatively affected wellbore and formation needs to be better assessed and periodically reevaluated as new information becomes available and the project progresses.
- **Lesson Learned:** Geothermal geology is different from oil and gas geology and each geothermal site may have very different geology from other sites. The impact of site geology on well design, drilling cost and potential drilling troubles needs to be carefully evaluated. For instance, drilling of serpentinite, a rock found in very few places in the world, should only be performed using properly conditioned drilling mud. Air drilling, especially misted air, and fresh water must not be introduced in the hole prior to casing installation. The value of experience in a particular area cannot be emphasized enough.
- **Lesson Learned:** When drilling in high risk formations, the bottomhole assembly should be configured for maximum potential success if fishing is required, and the use of expensive tools should be minimized.
- **Lesson Learned:** Written documentation for mitigation and communications planning should be developed before operations begin and submitted to DOE for review.
- **Lesson Learned:** Written procedures should be prepared for all key operations, especially cementing, and reviewed by those experienced in the procedure and with local knowledge. If the temperature of the rock during cementing cannot be measured, it should be modeled. At E7, personnel with a lack of local site experience did not formulate the appropriate cement composition, and failed to prepare and follow a written procedure to execute the task.
- **Lesson Learned:** Drilling in unstable formations and active reservoirs increases the risk of drilling trouble and fishing costs. These risks should be adequately factored into total

drilling cost, and mitigated with the use of site-experienced drilling personnel. The use of an existing well required more difficult direction drilling and more expensive tools in the hole. The use of expensive tools in problematic areas should be carefully weighed against lost-in-hole risk and cost.

- **Lesson Learned:** Beyond a certain time, the potential benefit of further fishing is reduced greatly. Past experience with fishing in the area should provide guidance for a limit on the length of fishing operations. The amount of time spent fishing should be based on the economic and operational issues associated with the effort for any particular situation.
- **Lesson Learned:** Site-specific experience requirements should be clearly delineated prior to job initiation, and maintained through project completion.
- **Lesson Learned:** Data reporting requirements, including confidentiality, format, distribution and frequency must be clearly delineated prior to commencement of operations and supported throughout the project.
- **Lesson Learned:** There is a clear need to communicate spending levels for a project in a timely fashion, especially when the actual vs. planned spend rates begin to differ. This information is critical to help make informed decisions for a project and for preventing significant issues related to reimbursement.
- **Lesson Learned:** Expenses must be closely tracked and reported to the funders, with clear up-to-date metrics comparing planned and actual spending.
- **Lesson Learned:** A rigorous site-specific EGS stimulation protocol must be established as part of project planning and receive support from regulatory agencies through project completion. The protocol should include:
    - Nature and extent of community education programs
    - Requirements for microseismic monitoring
    - Maximum observed event size to trigger reduction in injection rate. This should be based on modeling of what event size can be felt by the nearest populated area.
    - Acceptable distance fractures can grow toward sensitive features such as large faults or groundwater aquifers.
    - Response to seismic events that are felt by the public.
    - Set up for pressure reduction through flow back following stimulation.

9. References

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Appendix A – Timeline of Major Events

Event	Date
DOE Award Notification	26 Sept 2008
Award Negotiation Finalized	27 Mar 2009
Site Work Initiated	05 Jun 2009
BLM FONSI received	09 Jun 2009
Start E-7 Workover (Re-drill 3)	20 Jun 2009
New York Times article published	23 Jun 2009
Start Re-drill 4	29 Jul 2009
Start Re-drill 4A	14 Aug 2009
E-7 Workover Suspended	02 Sep 2009
DOE Signs FONSI for grant	11 Sep 2009
AltaRock release drill rig	Oct 2009
DOE publishes FONSI for grant	30 Dec 2009

Appendix B – Daily Summary of Events

5/27/2009 Moved in, rigged up Ensign Rig #305.

5/28 Nippled up and tested BOPE. Opened up well E-7, RIH with 13-3/8" casing scraper assembly and 2-7/8" tubing to 1725'.

5/29 While picking up tubing, RIH with scraper assembly to top of 9-5/8" liner at 3,301', POH and lay down scraper assembly. Attempted to run 13-3/8" 72# Select Oil Tools bridge plug, unable to get the bridge plug through the Master valve and wellhead.

5/30 Made up 13-3/8" Halliburton EZ Drill bridge plug, RIH and set bridge plug with top at 3289', POH and laid down setting tools. Pressure tested casing to 500 psi for 15 minutes, OK. RIH w/ 2-7/8" tubing open ended, circulated and pumped 10 bbls of Type 11-V 15.4 ppg cement on top of bridge plug (estimated 60 linear feet of cement from 3229' to 3289'), POH to 2329', circulated to clear tubing string.

5/31 RIH from 2329' to top of cement at 3226', POH and laid down excess tubing. Rigged up Schlumberger logging crew, ran USIT log from 3211' (wireline depth) to surface for cement and 13-3/8" casing inspection. Rigged down loggers.

6/01 Rigged down Ensign Rig, dug down cellar to remove and change out wellhead.

6/02 Installed Cameron 13-3/8" 5K wellhead, welding to casing. Graded and leveled location. Bolted DSA X-aver spool and new master valve together. Ran 12-3/8" taper mill through components to check drift.

6/03 Tested wellhead to 80% of collapse rating. 2100 psi OK.

6/04 Installed new master valve and put in new bolts on wing valves.

6/05-17 Finished location work, all equipment moved off location. Moved in, rigged up Nabors Rig #633.

6/18-19 Nippled up and tested BOPE. Tested blind rams and shell test BOP stack to 500 psi (OK).

6/20 RIH w/12-1/4”, tagged top of cement at 3228', cleaned out cement from 3228' to 3239'. POH.

6/21 RIH w/ Smith lnternational13-3/8" whipstock assembly to 3239', oriented and set with top at 3204'. POH. RIH with 12-1/4" Smith Tri-Mill, milled window from 3203' to 3241'.

6/22 Reamed window w/ mill, POH. Mill undergauge. Made up new 12-1/4" mill, RIH, jets plugged, POH. Cleaned jets.

6/23 RIH w/ 12-1/4" mill assembly, reamed window from 3203' to 3226', POH. RIH w/ directional assembly, directionally drilled 12-1/4" hole from 3241' to 3246'. Survey at 3203'.

6/24 Directionally drilled 12-1/4" hole from 3246' to 3345', POH.

6/25-26 Made changes to convert from mud drilling to air drilling.

6/27 RIH to 500', unloaded water with air, staged in hole to 3345' with directional tools and motor, motor would not drill, POH.

6/28 Changed out motor, RIH, no good, POH. Ordered new motor.

6/29 Picked up new motor and bit, RIH and unloaded hole and recovered huge amount of serpentine and clay. Directionally drilled 12-1/4" hole with air from 3345' to 3378'. Hole packed off with cuttings, pipe sticking.

6/30 Worked pipe free, pulled up to 3250', circulated and cleaned hole. Pulled up to 3132', mixed mud.

7/01 RIH to 3231' with 12-1/4" bit, reamed with mud to 3378' while cleaning out bridges from 3340' to 3344' and from 3370' to 3378'. Tight hole, POH. Made up slick drilling assembly, RIH to 3297', cleaned out bridges from 3342' to 3344' and from 3367' to 3378'. Pulled up and when reaming again down to 3341' hit bridge and was unable to clean out deeper. Appeared to be side-tracked.

7/02 Re-drilled 12-1/4" hole with mud from 3341' to 3385 and drilled to 3480', circulated clean, POH while having worked through tight spot at 3370' to 3383'. Survey at 3423'. Made up directional tools, RIH, tagged bridge at 3378', reamed to 3480'. Directionally drilled 12-1/4" hole with mud from 3480' to 3510

7/03 Directionally drilled from 3510' to 3696', Surveys at 3516' and 3612', pulled up to 3113' and repaired mud pumps. RIH and reamed from 3679'" to 3696', drilled 12-1/4" hole with mud to 3856'. Surveys at 3706' and 3801'.

7/04 Directionally drilled 12-1/4" hole from 3856' to 3964', Survey at 3896', POH to change bit. RIH to 3869', reamed to 3964' and drilled to 4090'. Survey at 3990'.

7/05 Directionally drilled from 4090' to 4209', Surveys at 4086' and 4181', lost circulation at 4120'. Mixed LCM, circulated, drilled to 4255' and had increased lost circulation. Mixed and circulated LCM. POH and waited. RIH to 4255', directionally drilled 12-1/4" hole to 4257', lost full returns. Spotted LCM pill and drilled with no returns to 4266', Survey at 4235'. POH.

7/06-07 Changed over equipment to air drilling. RIH w/ 12-1/4" bit, unloaded well at 481', staged in hole to 4266', directionally drilled with air and motor to 4280', POH.

7/08 Laid down motor, picked up new motor, RIH and tagged bridge at 3363', reamed from 3363' to 3385', RIH to 4246', reamed to 4280', drilled with air to 4311'.

7/09 Drilled 12-1/4" from 4311' to 4429', Survey at 4361', drilled to 4434' while losing pressure. POH.

7/10 RIH to 3381', worked pipe, reamed tight hole at 3380', could not get below 3382' because of high torque and pump pressure, pulled up to 3226', very tight, POH.

7/11 RIH with 12-1/4" bit to 3155', tagged bridge. Reamed clay ball out of casing, reamed clay from 3203' to 3329' w/ dry air. Well unloading. POH.

7/12 Changed over equipment to return to mud drilling. RIH to 3167', mixed mud.

7/13 RIH to tag fill at 3310', washed to 3315', RIH to 3348', washed to 3384', hole sidetracking. Drilled 12-1/4" hole to 3389', no luck to find old hole, POH. Picked up directional BHA, RIH to 3350'.

7/14 Ran Survey at 3412', oriented tool to get into old hole, directionally drilled to 3481', Survey at 3506', directionally drilled to 3585', Survey at 3576', POH.

7/15 Made up cement diverting sub on drill pipe, RIH to 3391', circulated and conditioned mud for cement job. Mixed and pumped 187 bbls of Halcem 1:1 perlite cement followed by 75 bbls tuned light cement displaced w/ 10 bbls fresh water and 50 bbls of mud. Full returns, CIP at 1200HRS. Pulled up from 3391' to 3011' and unable to circulate, pulled up to 2916' w/ 60K overpull, pulled up to 2883' with 250K overpull, unable to POH.

7/16 Wait on drill pipe (DP) recovery equipment. Ran inside drill pipe w/ star bit, tagged top of hard cement at 2361' (bottom at 2883'), POH. RIH w/ free point tools, DP free at 1716', POH. Contacted coiled tubing contractor to clean out inside of DP to conduct DP recovery operations.

7/17-18 Wait on equipment. RIH w/ 1-3/4" coil tubing w/ 2-2/8" mud motor and 2-2/5" bit to top of cement in DP at 2361'. Cleaned out cement to 2383', motor stopped, POH. Changed motor, RIH and cleaned out cement to 2883' (bottom of drill pipe). Circulated clean, POH.

7/19 RIH w/ wireline backoff shot, backed off drill pipe at 1674', POH. Made up wash over assembly, RIH to top of DP fish at 1669' (length of fish is 1214').

7/20 Washed over top of DP at 1669' w/ 10-3/4" wash over pipe, slid down to 1708', washed over to 1718', torque up, POH. Wash over shoe completely worn out. Made up new wash over shoe, RIH to 1714', washed over to 1721', torque up, POH. Wash over shoe again worn out. Made up jarring assembly, RIH, unable to screw into top of drill pipe fish, POH.

7/21 Made up screw-in sub, RIH, screwed into drill pipe at 1669', jarred on fish. Pipe parted, POH and recovered 1-1/2 joints. Top of fish now at 1716'. Pressure tested casing, OK.

7/22 Wait on tools. Made up BHA w/ concave mill with wash over shoe, RIH, washed over fish from 1716' to 1719', POH. Picked up new shoe, RIH, washed over to 1723'.

7/23 Washed and milled to 1727', POH. Picked up concave mill w/ wash over shoe, RIH, washed over and milled to 1731', POH. RIH w/ grapple, could not get good grip on drill pipe fish, POH. Waited for undersized overshot with grapple.

7/24 Made up BHA w/ overshot, jars and 4-7/8" grapple. RIH, worked over fish, set grapple and pulled with 75K overpull. Tripped jars. POH, made up new grapple. RIH, worked over fish, set grapple, pulled w/ 75K, 85K and then

95K overpull, overshot came loose, POH. Laid down overshot. Had two pieces of drill pipe side by side split. Fish top at 1727' w/ total length of drill pipe fish= 1,156'. Laid down tools.

7/25 Load out Weatherford tools. Tested casing to 950 psi, OK. Standby and wait on orders.

7/26-28 Nabors Rig #633 on standby.

7/29 Made up 13-3/8" casing scrapper assembly and RIH to top of fish at 1727', circulated and conditioned hole, POH and laid down scrapper assembly. Picked up 13-3/8" whipstock assembly, RIH and set whipstock at 170S', top of ramp at 1672'. Picked up 12-1/4" mill, RIH and milled window in 13-3/8" casing from 1672' to 1674'.

7/30 Milled window from 1674' to 1694' and continued to 1732', POH. Survey at 1676' Function tested BOPE. Made up window sizing milling assembly, RIH to 1732' w/ no bridges and 2' of fill, POH and laid down windowsizing milling assembly.

7/31 Made up 12-1/4" bit and BHA, RIH to 1732', drilled to 1744' and POH. Made up directional tools with 9-7/8" bit and 14-1/2" RWD (eccentric hole opener), RIH to 1744' and directionally drilled to 2010'. Surveys at 1899' and 1994'.

8/01 Directionally drilled 9-7/8" X 14-1/2" hole from 2010' to 243S'. Surveys@2088', 2183', 2278' and 2374'.

8/02 Continued drilling to 2714', POH. Changed bit, DWD and jars. RIH and safety reamed from 2636' to 2714'. Surveys at 2468', 2S63' and 26S9'.

8/03 Directionally drilled 9-7/8" X 14-1/2" hole from 2714' to 3208'. Surveys@27S5', 2849', 2945', 3040' and 3136'.

8/04 Continued to directionally drill to 3618'. Surveys at 3231', 3327', 3421', and 3S17'.

8/05 POH, picked up new motor, shock sub, RWD and bit, RIH. Directionally drilled 14-1/2" hole to 3760'. Surveys at 3612' and 3708'.

8/06 Continued directionally drilling 9-7/8" X 14-1/2" hole from 3760' to 3777' and lost mud returns. Spotted SO bbl LCM pill, POH. After 4 hr wait, RIH and established circulation, drilled from 3777' to 3839' and lost returns. Spotted SO bbl LCM pill, pulled up 120' to build volume, RIH and directionally drilled to 3856' while losing mud. POH, tight spots at 3425' and 3250' and tight at window. Total mud losses at 1040 bbls.

8/07 Wait on cementers. Made up Halliburton cementers, RIH to 3675' and conditioned hole. Pumped 160 sacks of perlite cement, displaced w/ 66 bbls of mud. Full circulation. Calculated 305 linear ft of cement. POH. Made up directional tools, RIH to 1750' and waited on cement.

8/08 RIH and tagged ratty cement at 3331'. Washed and reamed to 3575', drilled hard cement to 3855'. Survey at 3803'. Directionally drilled to 4001' and lost 100% of returns. Mixed and spotted 40 bbl LCM pill on bottom, worked pipe and waited on pill. Regained circulation, survey at 3895'. Drilled from 4001' to 4004'.

8/09 Drilled 9-7/8" x 14-1/2" hole to 4010', lost returns, POH. Waited on Halliburton. RIH to 3970', tagged bridge at 3970', washed thru bridge, RIH to 3980', tagged hard bridge, washed thru to 3998' and circulated down to 4010'. Mixed and pumped 160 sacks perlite cement at 13.2 ppg 2.3 cu/ft sack yield, displaced w/ 67 bbls mud, POH. Make up directional tools, RIH to 1592'.

8/10 Waited on cement. RIH to 3397', washed down to 3740' and tagged firm cement. Drilled firm cement to 4010'. Directionally drilled 9-7/8" x 14-1/2" hole to 4022', lost returns, spotted 40 bbls LCM pill. Survey at 3895'.

Directionally drilled to 4093', lost returns at 4090', circulated down 15 bbl pill while drilling and added 100#/hr LCM in suction pit. Survey at 3991'.

8/11 Directionally drilled to 4175' while losing returns and pumping sweeps to regain circulation. Survey at 4086'. Lost signal on EM tool, POH, laid down tools. Picked up bit, RWD, shock sub and NMDC and RIH to 1212', picked up EM tool, RIH to 3400, and circulated bottoms up.

8/12 RIH to 4080', safety reamed to 4175'. When making connection drill string became stuck at 4175'. Jarred on drill string with intermittent lost circulation. Mixed and spotted SO bbls LCM pill w/ 220 gals mineral oil w/ 110 gals "Lube 945" around BHA and worked stuck pipe. Unable to circulate, drill string plugged. Continued to jar on drill string.

8/13 Jarred on drill string, waited on orders. Jarred with increased overpull until jars failed. Waited on Baker-Atlas wireline pipe recovery equipment. RIH w/ weighted spud bars and spanner jars, tagged top of upper antenna sub and probe at 2940', POH. Made up backoff shot, RIH and backed off at 2910', pulled out Baker-Atlas, PO backed off portion of drill pipe.

8/14 RIH open ended to 1600', circulated and conditioned mud. RIH to top of fish at 2910', circulated and conditioned mud for Halliburton cementing operations. Pumped 11bbls of fresh water ahead of 51bbls (200 sacks) of "Halcem TM" cement mixed at 16.5 ppg, 1.44 cu.ft/sack yield. Displaced w/ 1bbl fresh water and 44.4 bbls mud. Full returns during entire job. Pulled up to 1961', woe. RIH, tagged top of cement at 2725', POH. Made up directional drilling assembly with 12-1/4" bit.

8/15 RIH to 2062', spot reamed bridges/ledges from 2062' to 2346', circulated and pulled out of window to 1590' to repair top drive. RIH, cleaned out bridges at 1855', 1887' and 2237', reamed from 2346' to top of cement at 2725'. Circulated clean, time drilled 12-1/4" hole to 2733'.

8/16 Time drilled 12-1/4" hole from 2733' to 2740' to kick off cement plug. Survey at 2725'. Directionally drilled to 3105'. Surveys at 2820', 2911', 2975' and 3039'.

8/17 Directionally drilled 12-1/4" hole to 3270', wiped hole up to 2346' (20k drag from 3270' up to 2740'), RIH and reamed out bridge at 2999', reamed from 3204' to 3270', directionally drilled to 3588', POH while backreaming tight spots at 3380', 3283', 3204', and 3180' to 3040'. Surveys at 3103', 3166', 3230', 3295', 3358', 3420' and 3484'.

8/18 Made up new bit, RIH, reamed bridges at 2434', 3472 and 3510', circulated bottoms up at 3588' (large amount of material came across shackers), directionally drilled 12-1/4" hole to 3775' while losing mud at about 75 bbls/hr. Surveys at 3561', 3658' and 3722'.

8/19 Circulated, pumped 80 bbl LCM pill, pulled up to 1600'. Mixed LCM in pill tank. RIH slow to 2660', safety reamed from3647' to 3775'. Circulated and worked pipe w/ full returns. Directionally drilled 12-1/4" hole to 3886' and lost circulation. Pumped and spotted 45 bbl LCM pill on bottom, pulled up to 1600'. Mixed mud, RIH to 3886', directionally drilled to 3910'. Surveys at 3786' and 3850'.

8/20 Directionally drilled 12-1/4" hole to 3948', circulated and pumped LCM pill, POH to 1600'. Built mud volume, RIH to fill at 1968' and circulated, RIH to 2916', circulated, RIH to 3775'. Safety reamed from 3775' to 3948'. Directionally drilled to 4102'. Surveys at 3913', 3977' and 4040'.

8/21 Directionally drilled 12-1/4" hole to 4167', circulated and pumped LCM pill. Wiped hole up to 3000', RIH and safety reamed from 4104' to 4167'. Lost returns, pumped LCM sweep, regained circulation. Drilled ahead to 4262', pumped LCM sweeps and mixed mud. Spotted heavy 50 bbl LCM pill on bottom. Pulled up to 1600'.

8/22 Built mud volume, staged in hole to 1709', attempted to circulate, pipe plugged, POH. Changed bit, cleaned LCM out of motor, RIH to bridge at 1735'. Reamed bridge, circulated clean, RIH to 1902', circulated and reamed to 2346'. Circulated clean, RIH to 2955' and reamed tight hole, pipe torqued up and stuck at 2981'. Jarred on tight pipe, jarred pipe up 27' to 2954'.

8/23 Jarred on stuck pipe. Rigged up Cogco wireline, ran freepoint, rigged down Cogco. Jarred on stuck drill pipe. Rigged up wireline to perform back-off.

8/24 Ran free point tool and backed-off drill pipe at 2788', POH leaving 166' of fish in the hole. Picked up fishing tools, RIH to top of window, circulated and conditioned mud, RIH and screwed into fish. Jarred on stuck drill pipe. Rigged up Cogco, ran freepoint and backed off at 2788'.

8/25 POH w/ wireline, line stuck and parted at rope socket, lost 18' of wireline tools inside fish. Picked up 8" drill collars and fishing tools, RIH to 1660' and circulated, RIH to 2590' (tight spot), washed and reamed to 2792' and circulated. Screwed into fish and jarred on fish. Ran Cogco wireline, rigged down Cogco. POH w/ fishing tools.

8/26 Made up screw-in-sub, RIH to 1641', circulated and conditioned mud, RIH to 2608', washed down to 2788' and circulated and conditioned mud. Screwed into fish. Rigged up "Vibration-Technologies" equipment. Vibrated on fish. Upward movement of about 1foot.

8/27 Vibrated on fish for an additional10 hours with no additional upward movement. Rigged down Vibration-Technologies equipment. Rigged up Cogco wireline freepoint equipment, RIH, freepoint at screw-in-sub area, POH. RIH w/ back-off stringshot, backed-off at screw-in-sub area, PO back-off tools & rigged down Cogco. Pulled up to above window.

8/28 POH. Top of fish at 2788' with 6-5/8" box facing up. Made up 12-1/4" slick reaming assembly, picked up new drilling jars, Ran in to 1644', circulated and conditioned mud. Washed and reamed from 1694', cleaning out bridges at 1780', 1792', 1799', 1800', 1830', 1870', 1878', 1890', 1900', 1908', 1930' and reamed to 2080'.

8/29 Washed/reamed, cleaning out bridges at 2105', 2111', 2122', 2156', 2188' and 2212'. Reamed to 2242' and circulated clean. Wiped hole upward, POH. Made up 9-1/2" bit, RIH, worked through tight spots at 1996', 2121' and 2131', reamed from 2131' to 2244' where forward progress slowed. Cleaned out to 2278' and unable to get deeper. Worked pipe and circulated clean at 2240', wiped hole upward to inside 13-3/8" casing. RIH to 2240' w/ no problems, circulated bottoms up, POH. Laid down excess tubular and prepared to set suspension cement plug.

8/30 RIH open ended to 1611', circulated and conditioned mud, RIH and hit bridge at 2238', pulled up to 2214'. Circulated and conditioned mud for cementing operation. Pumped 10 bbls of fresh water ahead of 40 bbls of Halliburton "Halcem TM" cement mixed at 16.5 ppg, 1.44 cu.ft/sack yield. Displaced w/ 1.4 bbls fresh water and 32 bbls of mud to balance. Full returns. Pulled up to 1454', circulated, waited on cement. RIH, tagged top of cement at 2178', pulled up to 1514'. Circulated and waited on Halliburton.

8/31 RIH to 2150', circulated and conditioned mud for cementing operation. Pumped 10 bbls of fresh water ahead of 52 bbls of Halliburton "Halcem TM" cement mixed at 16.5 ppg, 1.44 cu.ft/sack yield. Displaced w/ 1.4 bbls fresh water and 30 bbls of mud to balance. Full returns. Pulled up to 1390', waited on cement. RIH, tagged top of cement plug at 2021', POH. Closed master valve, rigged down to release rig and to suspend operations.